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The development of an integrated model for the assessment of water and GHG footprints for the power generation sector

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HIGHLIGHTS

- Assessed long term impacts of climate change on water consumption and GHG emissions.
- Evaluated cost effectiveness of various scenarios by developing water-carbon cost curve.
- Developed models in LEAP and WEAP that include demand tree, reference scenario.
- Coal to gas conversion will save water, reduce emissions while being cost-effective.
- Framework will help policy makers in other regions to develop climate change strategies.

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ABSTRACT

To ensure the use of water today does not damage the prospects for its use by future generations, there is need to understand long-term water demand and supply through energy production, conversion, and use. This study aims to develop an integrated framework to assess the long-term impacts of climate change scenarios on water requirements and greenhouse gas (GHG) emissions. The framework includes the integration of the Water Evaluation And Planning model (WEAP) and the Long-range Energy Alternative Planning Systems model (LEAP). As many countries are planning to move towards a cleaner electricity grid to mitigate climate change, this work attempts to present the impact of various scenarios on water demand, GHG emissions, and cost effectiveness. This is done by conducting a case study of the western Canadian province of Alberta where more than 85% of electricity is generated by fossil fuels. This paper provides a comprehensive overview of nine integrated LEAP-WEAP climate change scenarios for the years 2015–2050 by forecasting water consumption and greenhouse gas emissions from the power sector. The economic aspects of the developed scenarios are discussed in the form of a cost curve that shows the GHG saving potential, water use, and GHG mitigation costs for each scenario. For the Business-As-Usual (BAU) scenario (coal power phase out by 2030), GHG emissions and water demand will fall by 44% and 34%, respectively, in 2030. The integrated results show that the scenarios will mitigate carbon emissions but will result in higher water consumption, which will directly affect water resources in the region. Because of the high investment cost to install the considered renewable power plants in the climate change scenarios, the cost of mitigating carbon emissions in the power sector is high. Early coal-to-gas power plant conversion is the only scenario that is expected to save water (67 million m^3) and reduce emissions (40 million tonnes of CO_2 eq.) and be cost effective ($68/tonne of CO_2 eq.). These LEAP-WEAP model results can help create awareness among policy makers to understand the water-energy demand and supply relationship in a quantifiable way.

1. Introduction

Over the last two centuries, water management connection with energy has been deepened due to development of complex and resource intensive societies. Energy and water are valuable resources that support human prosperity and are interdependent (for power generation,

Abbreviations: AESO, Alberta Electric System Operator; AUC, Alberta Utilities Commission; BAU, Business-As-Usual; BCM, Billion Cubic Meters; CANSIM, Canadian Socio-Economic Information Management System; CLP, Climate Leadership Plan; CO_x, carbon oxides; GHG, Greenhouse Gases; GWh, Gigawatt Hour; HDI, Human Development Index; IPCC, Intergovernmental Panel on Climate Change; LEAP, Long-range Energy Alternatives Planning system; MWh, Megawatt Hour; NEB, National Energy Board; NGL, Natural Gas Liquids; NPV, Net Present Value; SO_x, sulphur oxides; TED, Technology & Environment Database; UNDP, United Nations Development Program; WEAP, Water Evaluation And Planning

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extraction, transport and processing of fossil fuels) [1,2]. Water and energy have a symbiotic relationship. Energy is needed for wastewater treatment, drinking water treatment, transmission and distribution of water, and water is needed for fuel production such as ethanol, hydrogen, extraction and refining, thermoelectric cooling and hydropower production. When discussing about water use and sectoral demand, it is important to distinguish between water withdrawal and water consumption. Water withdrawal (or water demand) represents the total water taken from a source (i.e. water body the water is withdrawn from), while water consumption represents the total amount withdrawal that is not returned to the source [3–5].

Water withdrawals for energy production globally in 2010 were estimated at 583 billion cubic meters (BCM) (15% of world's total water withdrawals) [6]. Of this withdrawal, 66 billion cubic meters is the water consumption – volume withdrawn but not returned to its source [6]. In United States in 2010, as estimated by United States Geographical Survey (USGS), about 41% of nation's available water was withdrawn by thermoelectric power plants [7]. In the energy sector, water requirement for fossil fuel-based and nuclear power plants are the largest.

Fig. 1 shows projection for global primary energy production and global water use for energy production which shows a 48% increase in energy consumption from 2010 to 2040 which translates to a 42% increase in water consumption [6,8]. Key drivers behind this increase in energy use and water consumption are population growth and increase in income per person. A chart developed by United Nations Development Program (UNDP) shows a direct correlation between electricity use per capita and quality of life, i.e., human development index (HDI) [9]. So, as we are aiming to improve our quality of life globally, we will be increasing our energy use. Currently, we rely primarily on fossil fuels which are increasing the global warming. So, one of our biggest challenges is to maintain an improving quality of life while decreasing the emissions from fossil fuels (mitigating climate change). Some options to mitigate global warming are:

- Reducing the greenhouse gases (GHG) through decrease in our energy use which can be achieved either by consuming less energy or using energy efficient equipment.
- Increasing our clean energy supply with renewables [10–13].

This study focuses on the later part i.e. increasing our clean energy supply with renewables. Further, under climate change mitigation, role of electricity generation mix is becoming more prominent, resulting in increased water demand for power plant cooling purposes [14]. This study focuses on water use for energy production primarily in electricity generation sector. A combination of technologies such as nuclear, fossils or biomass with carbon capture and storage and renewable sources characterized by diverse water requirements are the means for achieving decarbonization of electricity systems thus impacting the water resources [15–17].

Following the Paris climate change conference, one of the major

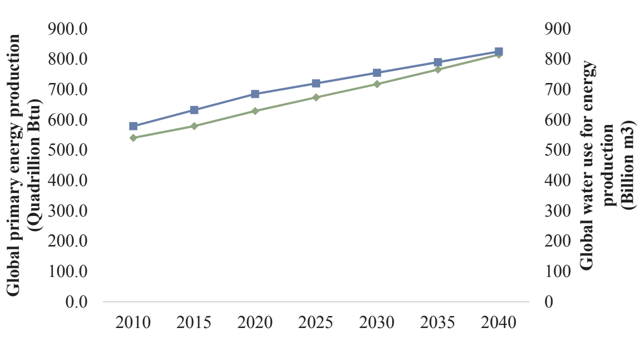


Fig. 1. Energy production and water consumption projection (2010–2040) [6,8].

outcomes is mitigating Greenhouse gases (GHG) emissions [18]. In electricity generation sector, coal generation pathway is the main source of carbon emissions. This study presents a case study of western Canadian province, Alberta, where more than 85% of electricity is generated by fossil fuels. Alberta is responsible for 65% of Canada's coal-fired electricity generation [19]. So, the success of Canada's move away from coal will be judged by Alberta's transition from coal to renewables. Also, Alberta has been the highest GHG emitter in the country since 2005 with 273 million tonnes of carbon emissions (out of 732 million tonnes) in 2014 [20]. In November 2015, Alberta government announced Climate Leadership Plan (CLP) which outlines the province's proposal to curb its emissions [21]. One of the key strategy outlined in the report is to end coal pollution by phasing out province's coal-fired power plants by 2030. Hence, Alberta's electricity generation sector is currently at an inflection point and a successful transition to cleaner sources of energy will set a guideline to upcoming states and countries for their transition. In Alberta, with the expected shift towards greener electricity grid (as highlighted in the Government of Alberta Climate Leadership Plan), it is critical to understand the impact of climate change mitigation efforts on water demand. Water use and consumption for the electricity generation sector will be highly influenced by proposed air emissions regulations and technology advancement to improve water intensity in power sector [22].

To make well informed long-term decisions, policy makers and resource managers need to fully understand the interconnections between energy production and water use, or water-energy nexus [23]. Planning and assessment issues require strategies to minimize the vulnerabilities around water and energy while mitigating the corresponding GHG emissions. Some studies on water energy nexus have been conducted in the past and a summary of literature review focused on water use and electricity production is described below.

Some of the papers discuss the impact of climate change mitigation scenarios on water demand or on energy sector indirectly affecting water demand. Climate change can impact energy sector (both demand and supply) in a number of ways such as changes in the efficiency of power plants, increased rainfall may enhance hydroelectricity output, but thermoelectric power may become vulnerable due to higher temperature and increases in peak demand due to higher cooling demand in hotter summers [24,25]. Climate change mitigation scenarios include adoption of renewable technologies like wind, hydropower, solar, carbon capture & storage, reduction of fossil fuel based power plants, etc. Mouratiadou et al. [26] present an integrated assessment model of water-energy-land-climate to assess the changes in electricity and land use, induced by climate change mitigation, impact on water demand under alternative socioeconomic and water policy assumptions. Nanduri and Otieno [27] propose a framework of a joint carbon and water cap-and-trade model to understand implications of electricity-water-climate change nexus and present a multi-agent reinforcement learning-based predictive model. Ciscar and Dowling [28] in 2014 presented a review on how integrated assessment models have estimated impacts of climate impacts and adaptation in the energy sector concluding that there is vast amount of work that needs to be done in order to understand the vulnerability of energy sector stating the fact that most important aspect is the adaptation options available in energy sector, their costs, effectiveness and potential. Water-energy nexus for Middle East and North Africa region was reviewed by Siddiqui and Anadon [29] which highlighted a weak dependence of energy systems on freshwater, but a strong dependence of water extraction and production on energy. Most of the Arabian Gulf countries consume 5–12% of the total electricity consumed for water desalination. Based on these studies, it can be summarized that research focused on integrated GHG and water footprints for energy pathways are limited. A big challenge as discussed by Sovacool and Sovacool [30] is to improve quality of research related to electricity-water issues. Currently, there are limited studies available that correlates water demand, greenhouse gas emissions and cost effectiveness of scenarios for an energy sector over long-term planning

horizon. This paper attempts to address this gap by developing a framework to assess water use and GHG mitigated for various climate change scenarios.

Also, as many countries are planning to move towards cleaner electricity grid to mitigate climate change, this work presents the impact of various GHG mitigation scenarios on water use for the sector. This is done by conducting a case study of western Canadian province, Alberta where majority electricity is generated by fossil fuels. The objective of this study is to develop an integrated water-energy system model to quantify the impact of various climate change scenarios on water resources for Alberta. From this, a scenario analysis was conducted to find impactful policy and technology alternatives to drive Alberta's level of sustainability forward without greatly sacrificing energy security or quality of life. These scenarios are also evaluated for economic suitability by developing a water-carbon cost curve for a comprehensive comparison of scenarios in terms of GHG abatement costs, GHG mitigation potential and water use. The Long-range Energy Alternatives Planning system (LEAP) [31] and Water Evaluation And Planning (WEAP) model [32] has been used to evaluate these options. The LEAP and WEAP models have previously been used to study the integrated energy and water demand for Alberta's energy sector predominantly petroleum sector to demonstrate the capability the two models [33]. Integrated LEAP-WEAP model have previously been employed by Dar et al. [34] to conduct research on water demand and GHG emissions for 3 energy scenarios predominantly in oil and gas sector. The results show the projection of water demand and GHG emissions for in situ and surface mining processes in bitumen extraction. Dale et al. [35] conducted an assessment of water-energy and climate change in Sacramento, California using WEAP and LEAP models and suggested that regional imports of electricity would increase by 35% in hot dry years. One interesting modeling attempt in the similar lines is the use of CLEW (Climate, Land, Energy and Water) model by Welsch et al. [36] to conduct a study for the Island of Mauritius by integrating various modeling approaches. The development of framework includes linking three models LEAP energy model, WEAP water model and AEZ (Agro-Ecological Zones land production planning) model with common assumptions and data. Huang et al. [37] assessed the impacts of carbon and water constraints on China's power sector by developing a bottom-up model to project water demand and carbon emissions in power sector for eight different scenarios. Dubreuil et al. [38] proposed a model to assess optimal water-energy mix in the water-scarce Middle east region. Srinivasan et al. [39] conducted a multi-model study to assess long term impacts of various policies on Indian power sector. They explored the implications of economic growth, power plant cooling policies, and power sector carbon reductions on water withdrawal and consumption. These studies also highlight the tradeoff between GHG emissions and water demand, however, one common limitation of these studies are that they do not consider economic aspect of the scenarios.

This work explains the methodology followed to develop an integrated water-energy system model primarily for power generation sector considering cost-effectiveness of various scenarios. In this study, authors assessed the impact of various climate change scenarios which considers various types of renewable energy penetration in Alberta's electricity generation grid. This study takes a closer look at power generation sector of Alberta and assesses the impact of recent announcement of coal power phase out by 2030. The specific objectives of this work are as follows.

1. Develop a baseline energy supply and demand in the LEAP and water supply and demand scenario WEAP model for the province of Alberta over a 35-year planning horizon.
2. Identify GHG mitigation options in the energy supply sectors of Alberta based on renewable energy penetration.
3. Estimate the potential for GHG mitigation and water use in different scenarios over two planning horizons of 2030 and 2050.
4. Perform a cost-benefit analysis to evaluate various GHG mitigation options with water use.
5. Develop a cost curve to rank the identified GHG mitigation pathways with water use for the Province of Alberta.

2. Modelling methodology

To develop a baseline energy supply and demand scenario, annual activity levels of the electricity generation sector along with various parameters were entered into the LEAP model for the supply sector. To develop the water supply and demand scenario, annual activity levels (MWh) of the electricity generation sector along with end-use water intensities were entered into the WEAP model. Both models work on a demand and supply resource balance. A key benefit of WEAP and LEAP is their seamless integration, and for that reason they were used in this study [32]. A business-as-usual (BAU) scenario was also developed for the years 2005–2050 to project the GHG emissions and water consumption from Alberta's power sector; these projections act as references in our evaluations of the impacts of various climate change scenarios. A water-energy nexus diagram was developed using the integrated LEAP and WEAP results. In this study, cost-benefit analyses of the scenarios were developed to evaluate the incremental costs incurred in each scenario compared to the baseline scenario. The incremental costs, along with water use and GHG mitigation potential, were used to develop the water-carbon cost curve. The overall methodology for developing cost curves is given in Fig. 2.

2.1. Water Evaluation and Planning (WEAP)

The WEAP model's graphical interface allows the user to develop a bottom-up demand tree, develop a business-as-usual scenario to forecast water consumption patterns, and evaluate water use impacts of climate change scenarios [32]. The model also allows the user to perform extensive cost analyses, and the results are provided in various formats (charts, tables, and summary reports). WEAP is a water demand and supply assessment tool with long-term water planning and forecasting capability [32]. It provides an efficient way to predict demand-source interactions and the effects of different parameter variations over time [32]. A more detailed information on WEAP model can be can be referred from WEAP user guide [32].

The schematic graphically represents the rivers, reservoirs, demand sites, transmission links, return flows, and stream-flow gauges (see Fig. 3). Geographic information system (GIS) vector files were imported into WEAP [32]. For the demand and supply model developed for Alberta, the six main river basins, along with their tributaries, locations of the stream-flow gauges installed along the rivers, and reservoirs were identified through Google Earth [32]. These vector files were imported into WEAP and represent the course of the rivers. The data view in WEAP consists of data input to the software that can build relationships between variables and user-defined assumptions for future projections [32]. Stream-flow gauges installed at various points in rivers capture the river water flow for a particular river every hour of each day. This stream flow gauge data was imported in WEAP for Historical years from 2005 through 2015 which were used to develop the water supply module of base case. Future projection of this pattern is used while developing BAU scenario, which considers the rainfall runoff and other necessary components required to model river basin. The river flow pattern is assumed to remain same for future years. It is assumed that the river water flow and the reservoir water volume patterns observed between 2001 and 2015 will repeat until 2050. The only projections available for rivers are based on WEAP climate model. Water routing in the WEAP model is used to account for total water supply in the province from which power plants withdraw water. Since, all power plants don't withdraw water from same river, major rivers in Alberta are modelled. The base year for this model is 2015 because this is the most recent year for which complete data are available. The time-step for the

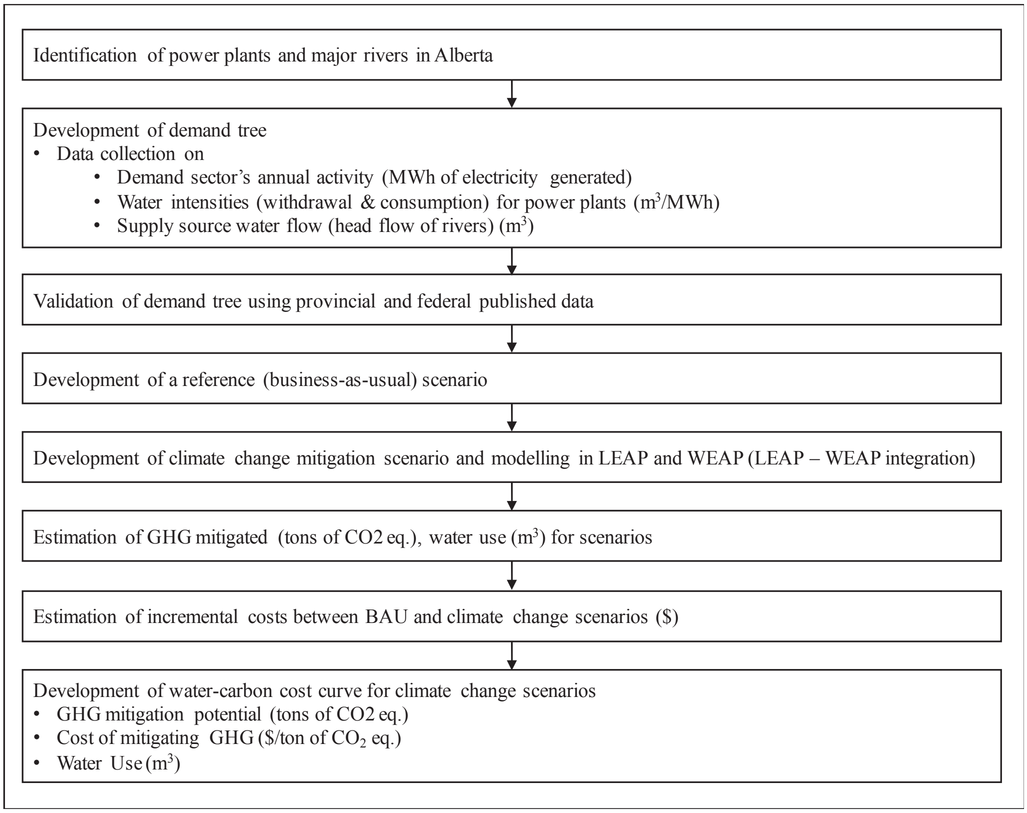


Fig. 2. Methodology for the development of water-carbon cost curve for Alberta.

model is one year and the supply module has been developed from year 2001 to 2050 with 2001 to 2015 as the base case. Reservoir volume tracked by Alberta Government and have been taken into consideration and modelled in this framework. The model was built in WEAP considering the demand and supply sides of all the water consumers in each river basin with a key emphasis on the power generation sector.

2.2. Long-range Energy Alternatives Planning (LEAP)

LEAP is an integrated computer-based energy-environment modeling tool designed to provide support in evaluating energy policies and sustainable energy plans [40,41]. It also allows the user to make projections of energy supply and demand over a custom-defined planning horizon (i.e., fifteen or thirty-five years). The model is data-intensive and can take into account the energy flow characteristics from reserves to final end use [40]. A more detailed information on LEAP model can be can be referred from LEAP user guide [31]. Fig. 4 shows different modules in LEAP model for Alberta.

The electricity demand in Alberta's five sectors (residential, commercial & institutional, industrial, transportation and agriculture) developed by Subramanyam and Kumar [43–45] has been used as input in this LEAP-WEAP model. Along with this, the "behind-the-fence load" (BTF) was modelled to account for the total electric demand in Alberta that is served by onsite generation, typically in industrial cogeneration plants [46,47]. In a transformation analysis, the LEAP model deals with the conversion and transportation of different forms of energy from the point of withdrawal of primary and imported fuels to the point of final fuel consumption. These modules are based on one or more processes that are further classified into input and output processes. These processes represent the individual technologies or a group of technologies that convert one form of energy to another or transmit energy [42]. Technology data such as fuel inputs to each process, capacities, efficiencies, capacity factors, and environmental loadings can be defined at this stage by linking Technology and Environmental Database (TED) to the process [41].

The input data for primary resources consist of reserves for the base year, resource imports, and exports for natural gas, coal, bitumen, crude oil, natural gas liquid (NGL), and pentanes [42]. The secondary resources include the fuels produced due to conversion of primary fuel to electricity, steam, etc. which are further used by demand sectors. In LEAP's Alberta model, the secondary fuels are electricity, steam, and refinery-finished products [42].

Environmental data for different kinds of pollutants (e.g., CO_2 biogenic, methane NO_x, CO_2 equivalent, particulates, and SO_x) are built into the LEAP model's TED. The corresponding global warming effects are also listed in the LEAP's database. All the transformation and resource sectors were developed based on Alberta's resource development and are associated with the corresponding emissions [42].

For a successful integration of LEAP and WEAP model both LEAP and WEAP areas must have same base and end years and must have same set of time steps [48].

2.3. Demand tree for Alberta power generation sector

2.3.1. WEAP demand tree

The demand tree for Alberta's power sector by identifying the types of power plants was developed, calculating their percentage share of electricity generation and modeling water use intensity data for the identified power plants in the WEAP model. All the power plants, from a 5 MW to 860 MW capacity were identified and included in WEAP model [49]. Based on Statistics Canada's CANSIM Table 153-0082, it was assumed that all the power plants in Alberta use freshwater either from rivers or water treatment plants [50]. Process variation in similar plants is not expected to be significant enough to have an impact on final water demand. When the base case was developed, 2015 was selected as the base year because of the availability of complete data. The demand tree for each subsector was developed based on water data collected from various sources, as explained in the following sections

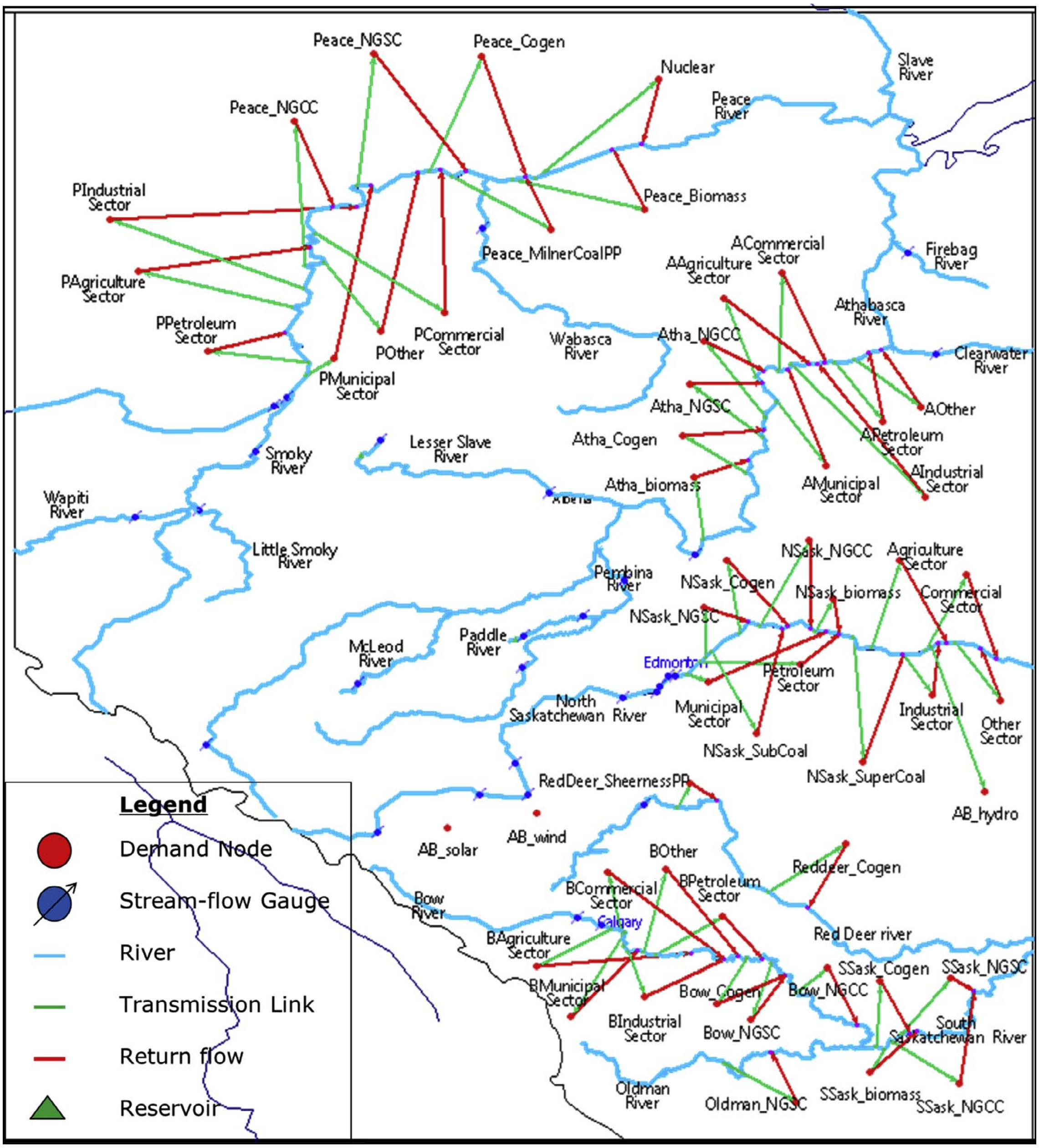


Fig. 3. Framework of WEAP model for Alberta.

(see also Fig. 5). Water use parameters for all the power plants and their corresponding capacity in base year 2015 are presented in supplementary sheet.

Actual water use by the power sector, in terms of water consumption (i.e., water withdrawal minus return flow), was estimated based on a combination of available water use reporting information and typical unit rates from the literature; these are discussed in the subsequent sections. This combination was necessary due to limited actual water use data available from Alberta Environment & Parks (AEP) [51]. As for the demand module, to satisfy water demand, WEAP has a supply module, which determines the amount, availability, and allocation of water supplies, and simulates monthly river flows. In the WEAP model for Alberta's power sector, the supply module was taken from an earlier study conducted by Dar et al. [34].

The water consumption results were calculated by WEAP model using a bottom-up demand tree based on Eq. (1):

$$\text{Annual power plant water consumption } (\mathrm{m^3})_{i,j} = \sum_{k=1}^{n} \text{power production } (\mathrm{MWh})_{i,j,k} * \text{Annual water use rate } (\mathrm{m^3/MWh})_{i,j,k} \quad (1)$$

i types of power plants in Alberta
j number of years with 0 as the base year, corresponding to 2015 in our case
k the total number of power plants of type "*i*".

Table 1 presents water withdrawal and consumption parameters for different type of power plants. Subcritical and supercritical coal plants in Alberta use wet cooling technology because of which consumption is high. Hydropower consumption level is at 100% because it is assumed that water evaporates in reservoirs which is water lost/consumed.

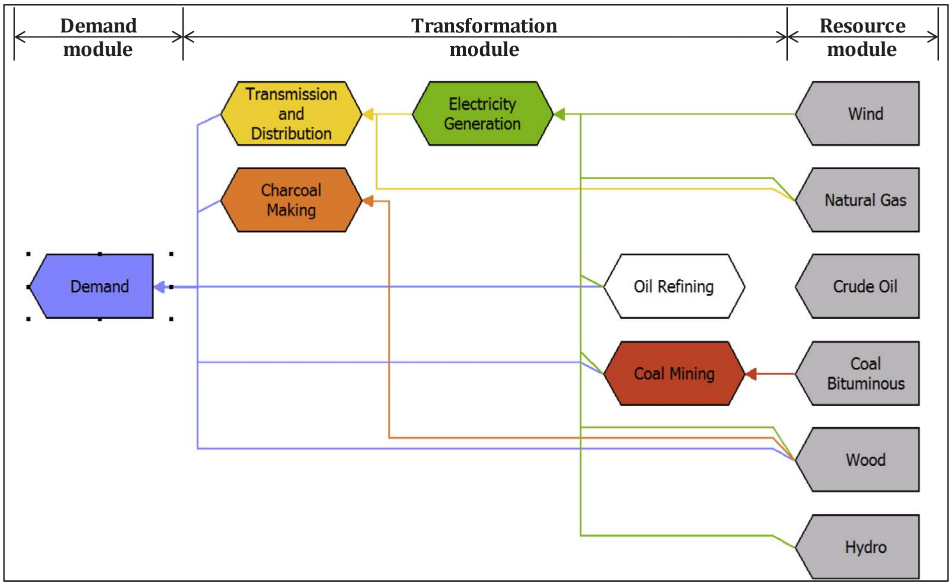


Fig. 4. Framework of LEAP model for Alberta [42].

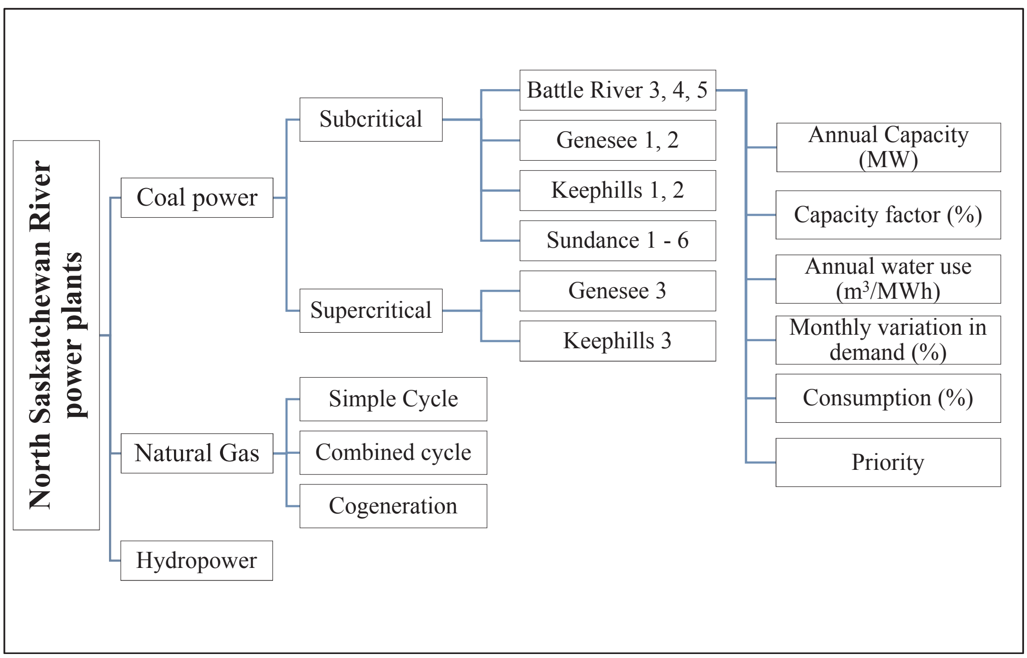


Fig. 5. WEAP Water demand tree and input parameters.

Table 1
Water demand coefficients for power plants in Alberta [4,5,51,52].

Power plant type	Withdrawal (m^3/MWh)	Consumption%
Coal subcritical	2.33	84
Coal supercritical	2.19	74
Natural gas simple cycle	0.38	80
Natural gas Combined cycle + cooling tower	0.90	75
Natural gas Combined cycle + Dry cooling	0.32	75
Natural gas cogeneration + cooling tower	0.69	65
Natural gas cogeneration + Dry cooling	0.25	65
Biomass + cooling tower	2.53	87
Nuclear + cooling tower	4.17	65
Hydropower	13.12	100

Water withdrawal is the water evaporated from the reservoir.

2.3.2. LEAP transformation tree

In LEAP model, the electricity generation sector is a transformation sector where fuel like coal, natural gas, hydro and wind, are converted into electricity, which is further used by the demand sectors. Fig. 6 shows the input parameters for developing the power sector the LEAP model.

In this study, input parameters for the electricity demand module from 2005 to 2010 are based on the National Energy Board's report [19]. Electricity demand projections from 2010 to 2050 are based on the energy demand tree developed by Subramanyam and Kumar [43–45]. The electricity demand module includes electricity consumption in the residential, commercial & institutional, industrial, transportation and agriculture sectors. Additionally, the BTF loads for cogeneration power plants were modelled.

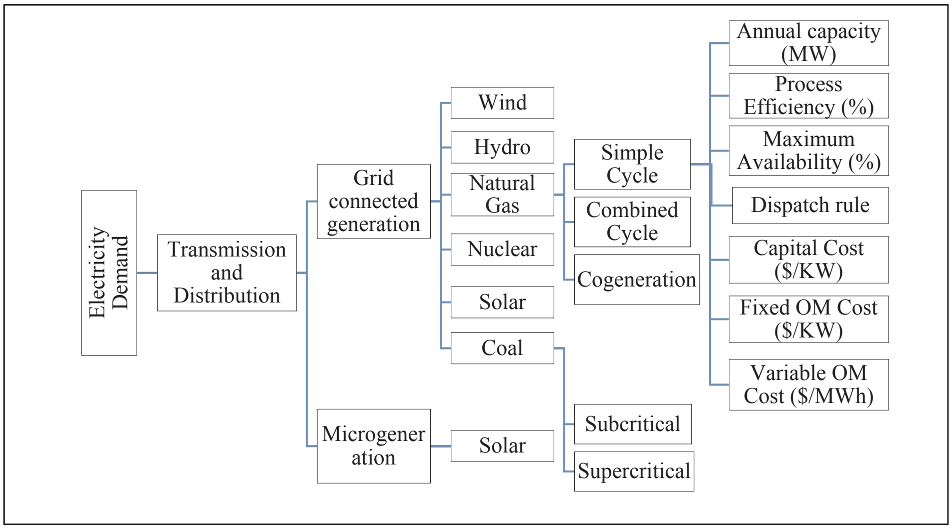


Fig. 6. LEAP power sector transformation tree and the input parameters.

In 2003, total annual system losses were 2765 GWh, or 4.45% of total energy transmitted – 62,089 GWh [53]. The Alberta Electricity System Operator (AESO) estimated electricity loss to be 3.84% on average in 2016 compared to an average system loss of 3.66% in 2015 [54]. Based on these figures, a system average loss of 3.5% was assumed for the future years in the LEAP model. The input data to the electricity generation module consist of plant availability, historical production, merit order, dispatch rule, system load curve, and process efficiency for each type of power generation unit selected. The total electricity production includes the MW generated in Alberta's oil sands for bitumen production and upgrading. The planning reserve margin for Alberta is assumed to be 30% based on AESO's 2015 long-term transmission plan [47]. Planning reserve margin represents the system generation capability in excess of that required to serve peak system load [55].

The emissions per unit of fuel consumed with respect to the technology considered were used for the demand sectors. TED module of LEAP contains a database of various sources on emission factors. The Intergovernmental Panel on Climate Change (IPCC) Tier 1 and Tier 2 emission factors for coal, natural gas, biomass, and wood are also specified in TED which were used in this study [42]. Net installed capacity from year 2005 to 2015 for different power generation pathway their emissions intensities are presented in supplementary sheet.

3. Scenario development and validation

3.1. Business-as-usual scenario development

Using the demand tree, a BAU case was developed in WEAP and LEAP models to understand the future water demand and GHG emissions in Alberta's power sector from 2015 to 2050. The BAU scenario was developed based on the AESO 2016 report, which projects the generating capacity for each electricity generation type from 2015 to 2037. Although Alberta is currently suffering an economic slowdown due to low crude oil prices, this study's BAU scenario assumes crude oil prices will recover and the oil sands industry and Alberta's economy will grow and increase the Alberta Internal Load (AIL). The AIL for the BAU scenario is assumed to grow rapidly from 2016 to 2018 due to oil sands projects currently under construction (over 550,000 bbl/d of oil sands capacity under construction and an additional 3.7 million bbl/day of capacity announced [56]) and the assumption that Alberta's economy will recover with peak AIL increasing to 13,700 MW by 2022 from 9162 MW in 2015 [46]. It is also assumed, based on third party forecasts, that by 2024 oil sands production will increase by approximately 1 million barrels per day from 2016 levels [19,56]. Post-2022 peak AIL is assumed to grow at an average annual rate of 2.5% to 2027 and 1.9% to 2037.

As discussed by AESO in its 2016 Long-term Outlook report, the BAU case assumes the Alberta Government will legislate the Climate Leadership Plan (CLP) and that the CLP will support the phase-out of coal-fired power plants by 2030 [21]. The Climate Leadership Report to Minister (CLRM) advises that 50–75% of retired coal capacity be replaced with renewables by 2030. The remaining 25–50% is assumed to be replaced by combined cycle and simple cycle gas-fired generation to support the integration of intermittent renewables and accommodate load growth. Further, in September 2016, the Alberta Government announced a target of 5000 MW clean energy by 2030 that will be served by wind, solar, and hydro [57]. Because of the great resource potential and cost advantages of wind generation, it is assumed that wind will be an appropriate technology to support near-term renewable penetration targets. An addition of 385 MW solar capacity is modelled in the BAU scenario based on solar PV projects under development (see Table 2) and assuming a 5000 MW addition of wind, an amount that will be difficult to meet through wind alone [58].

AESO reported 42 MW of biomass power in a connection queue and another 330 MW Amisk hydroelectric project currently in review phase that were modelled in a BAU scenario [59,60]. Geothermal and nuclear generation have large upfront capital costs and difficult regulatory processes, which makes them more suitable for long-term than near-term development [61]. After 2037, the growth rate for the years 2030–2037 was used to forecast the capacity addition for natural gas and wind-type power plants. For hydropower and solar type plants, projections are based on AESO's alternate mid-growth scenario. A 2013 report prepared for the Independent Power Producers Society of Alberta by EDC Associates projects 30,000 MW generation in Alberta by 2050 to

Table 2
List of solar PV projects under development in Alberta [58].

Name of the project	Capacity
GTE Solar at Brooks	15 MW
BluEarth Renewables, Burdett	20 MW
BluEarth Renewables, Yellow Lake	19 MW
Electricite de France (EdF)	68 MW
Brownfield site of Imperial Oil's former Leduc Gas Conservation Plant, Devon	23 MW
Suncor, Handhills	80 MW
Suncor, Forty Mile	80 MW
Suncor, Schuler	80 MW

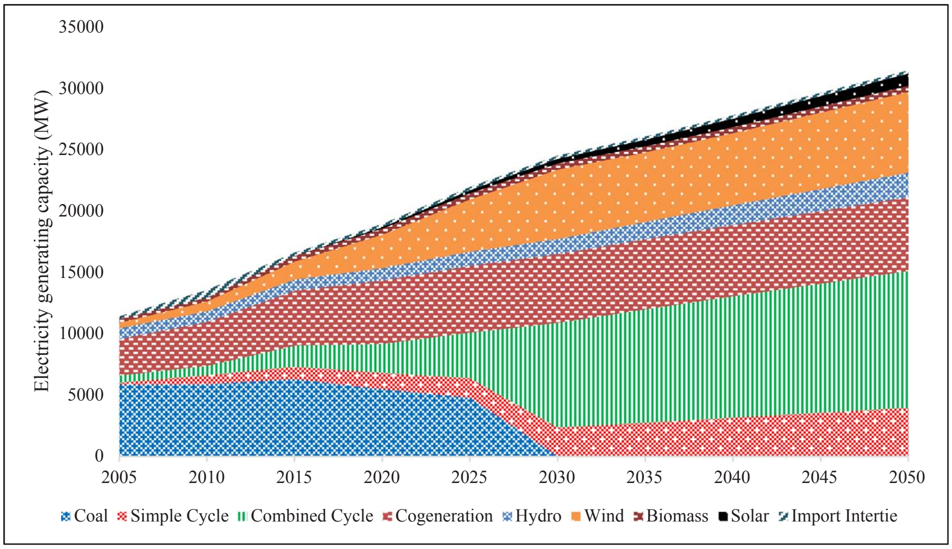


Fig. 7. Technology-wise generation capacity projection from the reference scenario for the years 2005–2050.

cover growing demand, and the developed model projects it to be 31,111 MW [62]. Fig. 7 shows the projection of capacity for various electricity generation types. In this figure, projections from 2016 to 2037 are based on AESO's 2016 LTO report [46] and projections for the years 2037–2050 are based on calculated growth rates.

It is assumed that for the study period water intensity for the electricity sector will not change [51]. As 90–95% of the water is used for cooling purposes and until new technology (such as dry cooling) is implemented in the thermal power generation, water intensity will remain constant. Due to the unavailability of data, the projection of GHG emission intensity for power plants is assumed to be remain constant as well. It is also assumed that cooling efficiency for thermal power generation for different fuel will remain constant throughout the study period. But due to change in generation mix, system cooling efficiency for power generation sector will change. Changes in hydropower generation due to increase/decrease in precipitation has been taken into account in BAU scenario based on AESO and other governmental reports.

The capacity factor for various technologies is assumed to be constant over the study period except for natural gas combined cycle plants, as presented in Table 3, which are based on AESO's 2015 Annual Market Statistics [55].

For the combined cycle power plants, since coal power plants will be phased out and will be replaced by natural gas combined cycle plants and wind power plants. So, to keep up with the generation, natural gas combined cycle power plant capacity factor must increase. In BAU scenario, there is a heavy coal capacity retirement in 2020 (794 MW), so it is assumed that capacity factor for combined cycle plant changes to 72% in 2020 acting as a baseload supply.

3.2. Alberta power sector validation

Model validation is an important step to verify accuracy. The values reported by the Alberta Utilities Commission (AUC) and the National Energy Board (NEB) differ because the AUC data is based on actual generation and the NEB data is based on demand met by the electricity sector; therefore, both are used for validation [19,63]. The LEAP model uses the power plant's process efficiency, exogenous capacity, maximum availability, merit order, and dispatch rule to calculate Alberta's total electricity supply required to meet demand. Hence, it requires these input parameters from the past several years.

The total annual electricity supply calculated by LEAP model shown in Fig. 8. The LEAP model results and the electricity generation figures reported by provincial and federal agencies are shown in Fig. 8.

Fig. 8 shows that the LEAP model closely follows the electricity generation pattern reported by the AUC and the NEB and thus can be used to forecast energy consumption in Alberta's power generation sector. Fig. 9 show validation by plant type. In Alberta, there are around 125 individual power plants that operate at different generation levels every day; hence, the capacity factor of each power plant is different. In addition, the dispatch rule in Alberta is dynamic; it changes every hour based on the lowest bid price. Therefore, small variations in electricity generation from each power plant type can be seen.

3.3. Climate change mitigation scenarios

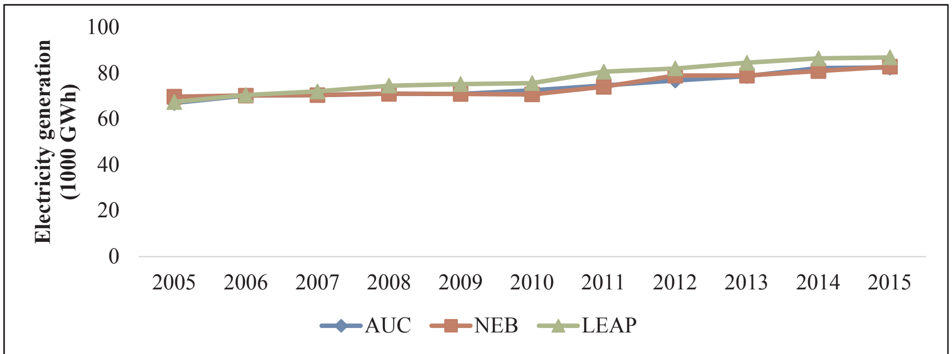
Alberta's electricity generation sector in 2015 included 16.74% electricity generation capacity from renewables, which was 9.44% of Alberta's electricity in the BAU scenario [49]. Based on various earlier studies from different organizations, several electricity generation mix scenarios are modelled to understand their impact on water sources in future.

The GHG mitigation scenarios for power plants were selected based on the literature review of the electricity generation mix and in discussion with experts and were developed in the WEAP and LEAP models. In power sector, unlike other sectors, most impactful scenario in terms of GHG emissions, will be one which considers change in generation type (for example replacement of natural gas power to wind power). Hence, various combination of renewable technologies has been taken into consideration as part of scenario analysis. The scenarios considered in this study cannot be implemented simultaneously because each scenario considers replacing natural gas capacity in

Table 3
Technology wise capacity factor for the forecast period [55].

Year	Coal	Simple Cycle	Combined Cycle	Cogeneration	Hydro	Wind	Biomass	Nuclear	Solar
2016–2050	80%	10%	32%, 72%*	60%	23%	32%	65%	90%	20%

* It is assumed that capacity factor of combined cycle power plant will increase from current 32% to 72% in year 2020 due to heavy coal retirement.



	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
AUC (Generation)	66.99	70.18	70.43	70.98	70.92	72.48	74.57	76.77	78.68	82.18	82.4
NEB (Demand)	69.7	70.2	70.4	71	70.9	70.7	74	78.9	78.9	80.9	82.8
LEAP Model	67.4	70.4	72	74.5	75.2	75.6	80.6	82	84.5	86.4	86.8

Fig. 8. LEAP model validation.

reference scenario with a combination of renewable energy. All the scenarios except scenario 8 and 9 discussed in this paper consider high penetration of renewable energy compared to BAU scenario. Scenario 8 and 9 consider conversion of coal power plants to natural gas plants. Water use and consumption for the electricity generation sector will be highly influenced by proposed GHG emissions regulations and technology advances to improve water intensity in the power sector [51]. Hence, climate change mitigation scenarios were developed to study the impact of regulations and technology improvements on water resources. These scenarios were developed using the BAU scenario as the baseline with changes in the electricity generation mix as input parameters. The penetration rate for each scenario was selected on a case-by-case basis depending on its implementation potential in Alberta between 2016 and 2050. Stillwell et al. and Yazawa et al. concur that future water trends in the power sector will be driven by a shift towards more efficient power plants with more advanced cooling systems and low carbon energy technologies [64–66]. The integrated model provides GHG mitigation potential and impacts on water resources for each scenario compared to the BAU, which reflects the accurate outcome of the new generation mix. All the GHG mitigation scenarios assume the same load growth as the BAU case but with a different generation mix. Nine scenarios were investigated in detail for this GHG emission and water analysis and are summarized in Table 4.

The penetration of renewable technology assumes generation (MWh) replacement as well as different scenarios to meet demand. One of the key aspects is that with capacity replacement is that different power plants have varying capacity factors, so direct one-to-one capacity replacement will result in unmet demand. To estimate the replacement capacity of technology 1 with technology 2, capacity factor analysis is used. Eq. (2) shows the estimation method:

$$CF_{T1}*GenCap_{T1} = CF_{T2}*GenCap_{T2} \quad (2)$$

Where,

CF_x = Capacity factor for Technology x
$GenCap_x$ = Generating capacity for Technology x

3.3.1. Scenario 1: AES1 – Alternate mid growth

The alternate scenario assumes the same load growth as the BAU case but with a strong interpretation of Alberta's Climate Leadership Plan. This scenario assumes that there is support for 9300 MW of renewables by 2037 instead of the 5000 MW assumed in the BAU scenario [46]. Because of higher levels of intermittent renewable development, more simple cycle capacity is added than combined cycle due to its faster ramp up and down rates [51]. The capacity additions up to 2037 were adopted from the 2016 AESO Long-term Outlook report [46]. After 2037, for each generation type other than hydropower, the 2030–2037 growth rate is assumed for future years. For hydropower plants, in the alternate mid growth scenario, 1100 MW is planned from 2015 to 2037 and it is assumed that 1100 MW will be added from 2037 to 2050.

3.3.2. Scenario 2: NUC2 – Nuclear energy penetration in Alberta's power sector replacing combined cycle

Nuclear energy penetration was not modelled in the BAU scenario because of its large capital investment and challenging regulatory processes [67]. Scenario 2 is based on a previous consideration of nuclear development by Bruce Power in Alberta [68]. In 2008, Bruce Power applied for a license to build a 4000 MW capacity nuclear power plant 30 km north of Peace River [69]. As part of the decision making process, the Nuclear Power Expert Panel was set up to present facts on nuclear power to Albertans [70]. The results of the Alberta Nuclear Consultation report show that 45% of Albertans were in favor of nuclear power plants on a case-by-case basis, 19% said government should encourage proposals, and 27% were opposed to proposals [71]. In late 2011, Bruce Power deferred the plan because of local residents' worry of the impacts on wildlife and water in the area [72].

In scenario 2, nuclear power generation is considered as a feasible long-term option for Alberta's growing energy needs. Nuclear energy is a reliable energy source and provides on-demand baseload electricity. Hence, nuclear power is well suited to replace combined cycle power plants. Based on the capacity factor analysis for the two technologies, a 1 MW nuclear power plant can replace a 1.25 MW combined cycle plant because the capacity factor of a nuclear plant by 2027 is assumed to be 90% and of a combined cycle plant, 72%. In terms of nuclear energy penetration, it is assumed that 2 nuclear reactors of 650 MW each will come online in 2028 and a 650 MW nuclear reactor will be installed in 2044. By 2050, the capacity of nuclear power generation will increase to 1950 MW and replace new combined cycle installations to meet 2437 MW of combined cycle capacity. This is based on the maximum level of considered generation for Alberta as per a corporate announcement by Bruce Power reported by AESO's generation planning forecast [69].

3.3.3. Scenario 3: NUC3 – Nuclear replacing cogeneration plants, supporting oilsands growth

The background for the consideration of nuclear energy is discussed in the previous section. Although there are currently no plans to

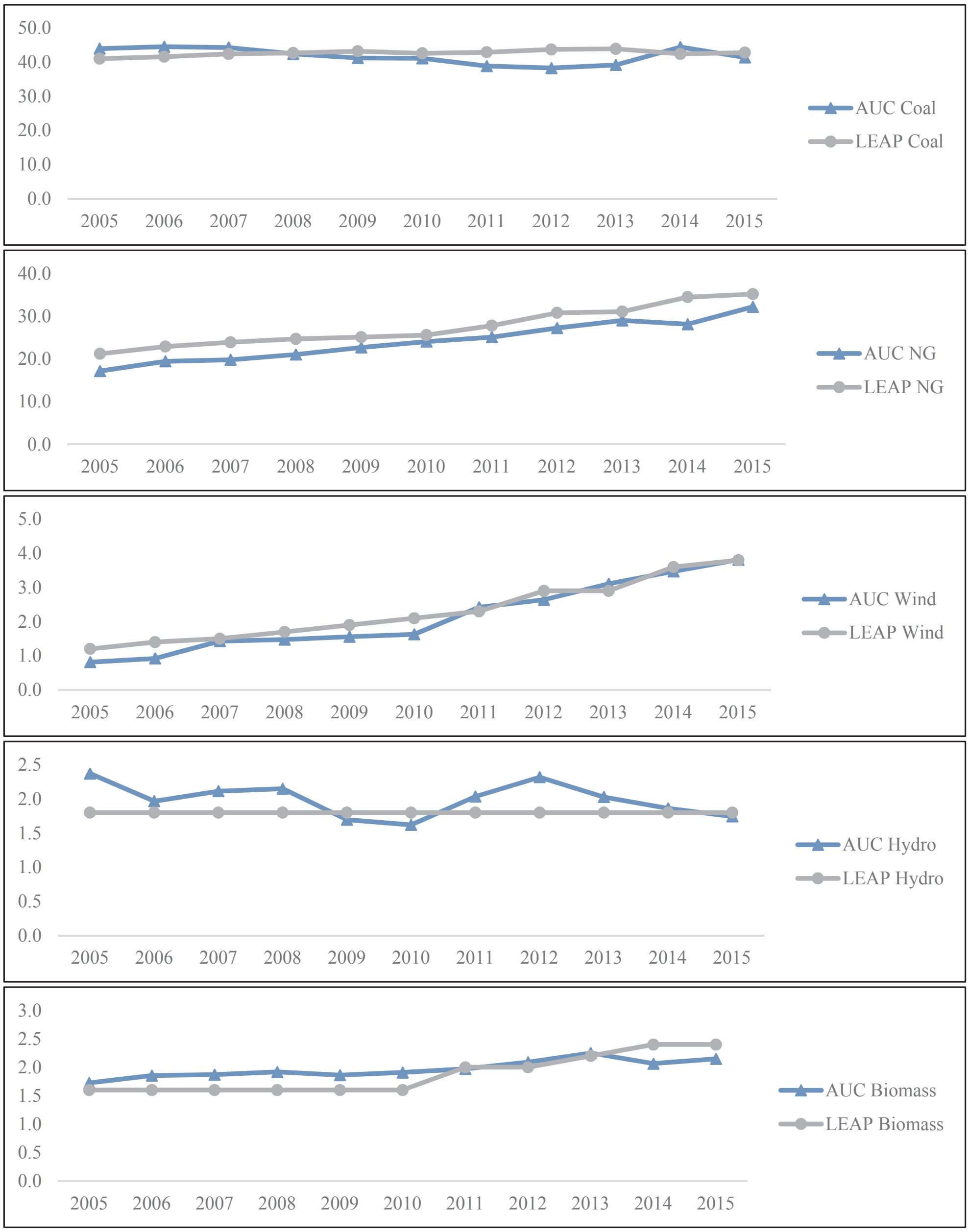


Fig. 9. Alberta Power generation validation (Electricity generation in 1000 GWh).

construct a nuclear power plant in Alberta, the oil industry has expressed interest in nuclear energy and considers it to be a serious option, provided that the technology meets industry technical requirements, such as steam pressure [73]. This scenario is modelled considering Canada's goal to reduce GHG emissions by 30% in 2030 from 2005 levels [74]. It is assumed that current cogeneration plants of 3396 MW capacity in the Athabasca region are replaced by 1300 MW nuclear energy in 2028 and another 650 MW in 2044, together replacing 2925 MW of cogeneration capacity by 2050.

3.3.4. Scenario 4: HYD4 – Hydropower plant replacing combined cycle plants in Alberta

At present, Alberta generates 894 MW (1745 GWh annually) of hydroelectricity [63]. The ultimate hydroelectric energy potential that could be extracted is about 42,000 GWh per year [29]. Approximately 75% of this potential is from northern Alberta (the Athabasca, Peace, and Slave river basins) and the rest is in the Red Deer, North Saskatchewan, and South Saskatchewan river basins. A 2010 report on Alberta's hydroelectric energy resources for the Alberta Utilities Commission believes that major projects in the northern basin and smaller projects in the southern basin can be developed in the next 30 years [75]. According to the report, in this period total hydropower development could be as much as 20% of the ultimate potential, i.e., 10,600 GWh per year. Based on this 10,600 GWh, around 5260 MW of hydropower plants can be developed by 2040 considering a 23% capacity factor. A new capacity of 5260 MW hydropower seems overambitious due to the high capital investment; therefore, in this scenario, an increment of 1100 MW hydropower is considered by 2037 (894 MW is planned for the BAU scenario) based on AESO's alternate mid growth scenario and another 1100 MW by 2050. Hydropower, a reliable source, is an ideal means of replacing 704 MW from combined cycle power plants, based on a capacity factor analysis. Hydropower in northern Alberta can be integrated with oil sands. The assessment was carried out by the Canadian Energy Research Institute [76,77].

In early 1980 s, two large hydro projects in the province were investigated for Dunvegan hydro, one on the Peace River and the other on

Table 4
List of GHG mitigation scenarios considered in this study and their key assumptions.

Scenario	Acronym	GHG mitigation scenario considered	Assumption
Scenario 1	GHG1	Increased renewable penetration	9300 MW of renewables added by 2037; (% renewables by 2030 = 40.9%) 600 MW of new wind added each year from 2018 to 2029 100 MW of solar generation capacity added annually from 2020 to 2029 and another 378 MW by 2050 330 MW and 770 MW of hydro generation in 2027 and 2036, respectively, and another 1100 MW by 2050.
Scenario 2	NUC2	Nuclear energy penetration in Alberta's power sector replacing projected combined cycle	Two 650 MW reactors by 2028 (1300 MW) replacing 1625 MW NGCC Another 650 MW by 2044 replacing 812 MW NGCC
Scenario 3	NUC3	Nuclear energy penetration in Alberta's power sector replacing Athabasca cogeneration activity	Two 650 MW reactors by 2028 (1300 MW) replacing 1950 MW cogeneration Another 650 MW by 2044 replacing 975 MW cogeneration
Scenario 4	HYD4	Hydropower penetration in Alberta's power sector replacing projected combined cycle	330 MW and 770 MW of hydro generation in 2027 and 2029, respectively, replacing 352 MW NGCC by 2030 Another 1100 MW by 2050 replacing 352 MW NGCC
Scenario 5	BIO5	Biomass - whole tree based biomass power penetration in Alberta's power sector replacing projected combined cycle	In Alberta, mixed hardwood and spruce are abundantly available and could be used to support a large power plant for 30 + years; assumed forest biomass yield of 84 dry tonnes of biomass per hectare 2000 MW of whole tree biomass by 2030 replacing 1805 MW of NGCC
Scenario 6	BIO6	Biomass - forest harvest residue based biomass power penetration in Alberta's power sector replacing projected combined cycle	Yield of forest harvest residue is 0.247 dry tonnes of residue per gross hectare. 2000 MW of forest harvest residue biomass by 2030 replacing 1805 MW of NGCC; forest residue potential = 2655 MW
Scenario 7	BIO7	Biomass-agricultural straw based biomass power penetration in Alberta's power sector replacing projected combined cycle	A study on biomass potential suggests an additional 6–7 million dry tonnes of straw is available per year that can support a ca. 2000 MW power plant from uncollected straw alone. 2000 MW of agriculture straw biomass by 2030 replacing 1805 MW of NGCC
Scenario 8	CTG8	Late conversion of coal power plants to gas power plants	6 coal power plants that could continue to operate beyond 2030 are converted to natural gas power plants by 2029.
Scenario 9	CTG9	Early conversion of coal power plants to gas power plants	6 coal power plants that could continue to operate beyond 2030 are converted to natural gas power plants by 2025.

the Slave River along the Alberta-Northwest Territories boundary [75]. The projects were considered for prospective large hydro development by early 2000 s. The Peace River project would develop an estimated 38.8 m of gross head with an installed capacity of about 900 MW. The estimated construction time is 9.25 years. Based on AESO figures, this converts to an annual production of just over 4300 GWh (assuming a 54% capacity factor). The Slave River project has an estimated head of about 35 m and a projected installed capacity of 2000 MW. The Government of Alberta developed these estimates in the early 1980 s but neither project has been developed, largely due to financial risk, high cost, long lead time, and concerns over environmental impact. The Dunvegan site was recently approved for a 100 MW low head run-of-river development that is not yet under construction. The Slave River hydro project was recently looked at by private developers [78].

3.3.5. Scenario 5: BIO5 – Biomass whole forest replacing combined cycle plants

Forest and agricultural biomass are the two main potential sources of biomass-based energy production in Alberta. According to earlier studies on the potential of biomass in Alberta, approximately 7 million bone-dry tonnes of forest biomass (e.g., forest residues) and 15 million bone-dry tonnes of agricultural biomass (e.g. crop residue or straw) are produced per year in Alberta for an energy content of about 380–420 petajoules [79]. In Alberta, mixed hardwood and spruce are abundantly available and could be used to support a large power plant over a period of 30 + years with a forest biomass yield of 84 dry tonnes of biomass per hectare [80]. A whole forest biomass potential of 2655 MW is identified based on research by Weldemichael [81].

This scenario considers of the use of whole trees for power generation. Biomass is considered to be a baseload power source ideal for replacing a combined cycle power plant [82]. In this study, a capacity replacement of up to 2000 MW is assumed by 2030 based on 84 dry tonnes biomass replacing 1800 MW of power from natural gas combined cycle plants.

3.3.6. Scenario 6: BIO6 – Biomass agricultural straw replacing combined cycle plants

Agricultural biomass in Alberta consists mainly of wheat and barley straw. A recent study suggests that about 6–7 million dry tonnes of straw is available per year after the current use of straw is considered [83]. This scenario considers the use of agriculture straw biomass for power generation. Biomass is considered to be a baseload power source ideal for replacing a combined cycle power plant [82]. In this study, the capacity replacement of up to 2000 MW is assumed by 2030 replacing 1800 MW of power from natural gas combined cycle plants. 2000 MW biomass power plant potential from agriculture straw is taken based on published yield data [80].

3.3.7. Scenario 7: BIO7 – Biomass forest residue replacing combined cycle plants

Forest residues are the limbs, tops, and branches that remain after the logging operations. The current practice for harvesting trees in Alberta involves felling the trees in the stand, dragging them to the roadside, delimbing them on the roadside, and transporting the main stem to pulp and lumber operations. The residue generated by delimbing is known as forest residue. It is forwarded, piled, and then burned to prevent forest fires. This residue is estimated to constitute about 15–25% of the total biomass of a tree [83]. In Alberta, forests have an average rotation period of 100 years; the yield of forest residue can be considered 0.247 dry tonnes of residue per gross hectare [80,81].

This scenario considers the use of forest residue biomass for power generation. Biomass is considered to be a baseload power source ideal for replacing a combined cycle power plant [82]. In this study, a capacity replacement of up to 2000 MW is assumed by 2030 replacing 1800 MW of power in natural gas combined cycle plants.

3.3.8. Scenario 8: CTG8 – Conversion of coal power plants to natural gas by 2029

This scenario was developed based on the announcement by TransAlta to convert their coal power plants to gas in order to help meet

Alberta's GHG emissions reductions target [84]. This scenario assumes the conversion of six coal power plants that could continue to operate beyond 2030 to gas plants [21]. The modifications needed to switch a coal boiler to natural gas include new gas burners and piping, combustion air ductwork and control damper modifications, air heater upgrades, gas recirculating fans, control systems modifications, and other site-specific modifications, as well as any pipeline installation that would be necessary to supply the unit's gas combustion following the conversion [85]. For this analysis, based on the United States Environmental Protection Agency's (US EPA) assumptions on cost and performance associated with coal-to-gas conversion, a 500 MW pulverized coal unit would have a capital cost of $137/KW (with the base year as 2014) to convert the boiler so that it could burn natural gas [85]. Further, it is assumed that due to a reduced need for operators, maintenance materials, and maintenance staff, fixed O&M costs would be reduced by 33% and variable O&M costs by 25% through reduced waste disposal, auxiliary power requirement, and other miscellaneous expenses [85]. The average capital cost of constructing new pipelines is assumed to be approximately $1 million per mile of pipeline built [85]. The pipeline requirement was estimated based on the nearest source of natural gas production, which is 50 miles for Genesee 1, 2, and 3, and Keephills 3 power plants and 20 miles for the Sheerness plant.

3.3.9. Scenario 9: CTG9 - conversion of coal power plants to natural gas by 2025

This scenario considers an early conversion of coal power plants to natural gas plants and assumes the conversion of coal power plants to gas by 2025 with the same assumptions as those made for scenario 8.

3.4. Cost of mitigating GHG

The cost of GHG mitigation in each scenario was investigated. The analysis, carried out in integrated LEAP-WEAP model, is not intended to provide an analysis of financial viability. Instead, it is a detailed cost potential of each scenario throughout the proposed project's lifetime, converted to its present value, i.e., 2015. The scenarios developed for Alberta power plants to identify impacts on water consumption involve different technology implementation costs, i.e., capital and operating & maintenance costs. In the WEAP model, new data variables were created to model the capital costs, fixed and variable operating costs, and capacity factors of different power plants. Using these parameters, the cost of mitigating GHG considering the BAU scenario as the base was calculated, which allowed us to perform an incremental cost analysis with different electricity generation mixes. GHG mitigation costs are typically calculated by dividing the net present incremental cost by the total GHG mitigated (calculated in LEAP) in a timeframe with units of $/tonnes of CO_2 eq. Additionally, incremental water use for the scenarios with respect to the BAU scenario was calculated from the WEAP model and combined in a water-carbon cost curve. Eqs. (3)–(6) show how the cost analysis was conducted in this study.

$$\text{Cost of GHG mitigated} = \frac{\text{Incremental cost of electricity production}}{\text{Total GHG mitigated}} \tag{3}$$

$$\begin{aligned}\text{Incremental cost of electricity production}\\ &= (\text{ACC} + \text{FixedO}\,\&\,M + Variable O\,\&\,M)_{\text{Scenario xyz}}\\ &\quad -(\text{ACC} + \text{FixedO}\,\&\,M + Variable O\,\&\,M)_{\text{BAU}}\end{aligned} \tag{4}$$

$$\text{Annualized Capital Cost(ACC)} = \text{CC}{*}\text{CRF} \tag{5}$$

$$\text{Capital Recovery Factor (CRF)} = \frac{i(1+i)^n}{(1+i)^n-1} \tag{6}$$

where,

i = discount rate
n = life of the equipment/power plant
Fixed O&M = Fixed Operating & Maintenance Cost
Variable O&M = Variable Operating & Maintenance Cost

Table 5 shows the input parameters used for calculating the cost of mitigating GHG. Cost parameters for each power plant were developed after data were gathered from the literature and harmonized and updated it to the 2015 Canadian dollar. Location factors of 1.08 and 2.16 were used for capital cost and fixed O&M cost for the conversion of cost data from the US Gulf Coast to Alberta, Canada [86]. Fuel prices were calculated based on Alberta's coal price (1$/GJ) and varying natural gas costs from NEB projections [19,87,88]. The cost data for various scenarios were converted to 2015 Canadian dollars and corrected to consider inflation based on Bank of Canada rates where applicable [89,90]. The discount rate in the economic analysis was considered to be 5%, a figure used in similar recent studies on GHG mitigation [91,92] (Fig. 10).

4. Results and discussions

A demand tree was used to calculate the base year electricity supply, GHG emissions from power plants, and corresponding water withdrawal and consumption, on which the BAU scenario was developed for the study period (2005–2050). This section discusses the GHG emissions and water withdrawal profile considering projected power plant generation as calculated by the LEAP and WEAP models. The electricity supply from coal power plants in Alberta will be zero by 2030, and these plants will be replaced by natural gas and renewable plants. Combined cycle and wind will absorb 90% of the projected load in Alberta after 2030, as shown in Fig. 11.

For water demand, we used the generation levels from 2005 to 2015 and the water use intensities of power plants to calculate net water consumption for the base year in the WEAP model. Fig. 12 shows the water consumption as calculated in the WEAP model for each technology.

The synergies and tradeoffs between water resources and power generation have interesting implications for integrated decision making and policy in Alberta. Total water consumption for the year 2015 was estimated to be 124.51 million m^3. In the base case year (that same year), coal power plants consumed the largest amount of water (64.81%) followed by hydropower plants (18.98%). The large amount of water consumption by coal power plants is partly due to larger electricity generation and a relatively high-water consumption intensity.

Figs. 13 and 14 show expected water consumption and GHG emissions, respectively, from 2015 to 2050 in the business-as-usual scenario. Water consumption is expected to decrease drastically from the base year value of 124.51 million m^3 to 98.08 million m^3 in 2050 and GHG emissions will also fall drastically, from around 52 million tonnes in 2015 to around 29 million tonnes in 2030 and 33.6 million tonnes of CO_2 eq. in 2050. This is predominantly because coal power plants are scheduled to retire by the end of 2030.

The results generated in the WEAP model on water demand for all developed scenarios compared to the BAU scenario are summarized in Fig. 15, and corresponding GHG emissions are shown in Fig. 16. The results from the energy and water modeling and implementation of GHG mitigation scenarios for Alberta's power sector as developed in the LEAP and WEAP models were discussed in detail. The economic aspects are shown in cost curves that compare GHG savings potential, water use, and GHG mitigation costs.

To make an informed decision and evaluate the potential of implementing multiple scenarios in Alberta's power sector, one should compare the scenarios in terms of cost as well as the potential to reduce water consumption. A comprehensive comparison of the costs and water savings potential of the scenarios developed in this study is presented through a cost curve developed from the LEAP and WEAP model results. The LEAP model simulates the GHG savings potential of

Table 5
Power plant Input parameters for cost calculation and its source in 2015 CAD.

Power plant type	Overnight capital cost ($/KW)	Fixed O&M cost ($/KW)	Total Variable O&M cost ($/MWh)	Fuel cost ($/MWh)	Heat rate (GJ/MWh)	Source
Subcritical coal	1666.47	47.07	3.32	10.50	10.5	[53,87,93,94]
Supercritical coal	2309.14	47.07	3.32	9.37	9.4	[53,87,93,94]
Simple cycle	1258.07	18.98	18.50	36.00	9	[53,86,88,95]
Combined cycle	1594.71	9.30	2.60	18.40	8	[19,53,90,93]
Cogeneration	1499.03	8.72	3.32	44.00	11	[19,53,90,93]
Nuclear	7302.34	246.35	2.62	3.50	–	[88,95]
Biomass straw	3082.21	88.45	62.98	Included in O&M	–	[80,96,97]
Biomass whole tree	2854.40	80.41	56.28	Included in O&M	–	[80,96,97]
Biomass forest residue	2854.40	80.41	69.68	Included in O&M	–	[80,96,97]
Wind	2952.69	105.54	0.00	0.00	–	[53,86,88,95]
Utility scale solar PV	4688.09	59.77	0.00	0.00	–	[53,86,88,95]
Hydroelectric	4038.51	38.87	0.00	0.00	–	[53,86,88,95]

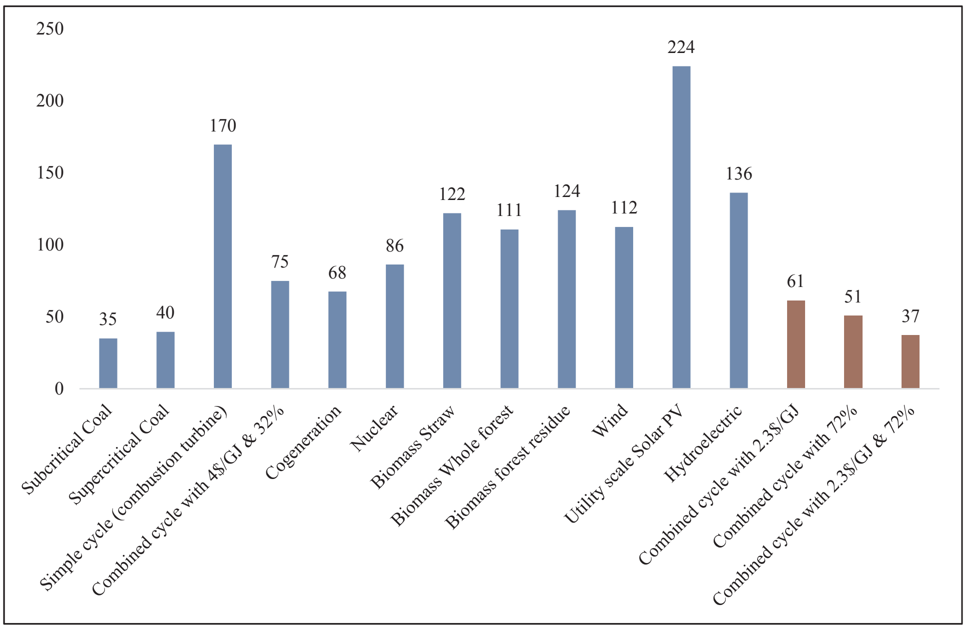


Fig. 10. Levelized costs for different generation types for Alberta (2015 CAD $/MWh).

various scenarios and estimates the net present value (NPV) of investment, and the WEAP model calculates the water use for each scenario, thus providing the water-carbon cost curve. To communicate a potentially complex analytical results in a simple and visual manner, we have developed water-carbon cost curve in the form of bubble chart that depicts three axes i.e. cumulative GHG emissions over planning

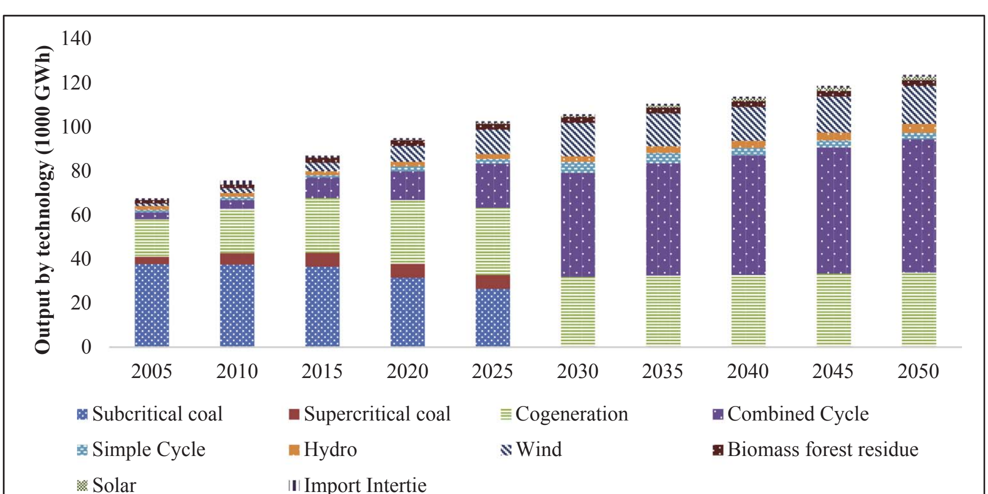


Fig. 11. Technology-wise share of electricity supply as projected by LEAP for the reference scenario.

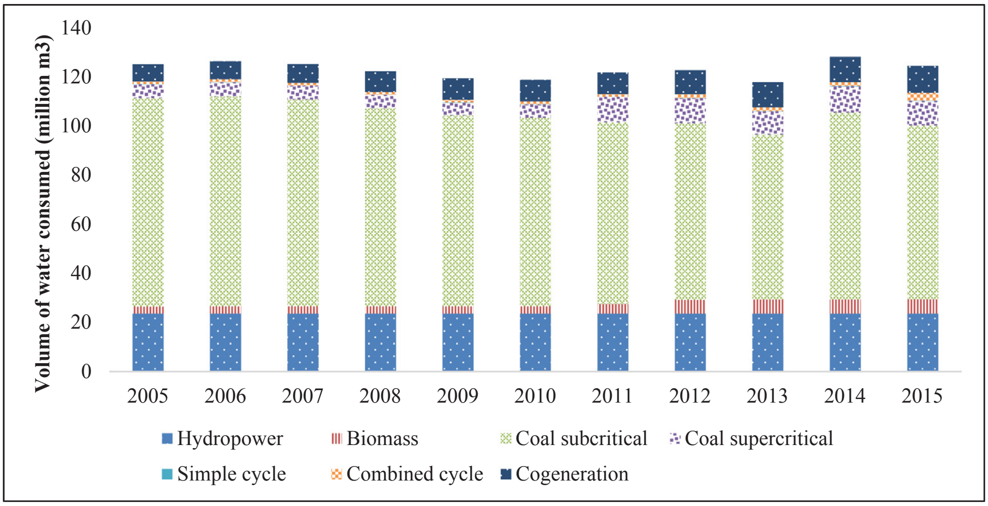


Fig. 12. Technology wise share of water consumption for base case years.

horizon (2015–2030 for 2030 planning horizon), cost of mitigating one tonne of CO_2 eq. and water saving potential over the planning horizon. In the cost curve shown in Figs. 17 and 18, the x-axis value is scaled based on net GHG mitigated during the study period, i.e., planning horizons to 2030 and 2050, and the y-axis value indicates the cost per unit GHG mitigated. The x-axis is a number cumulative over the planning horizon and not the cumulative of different scenarios. The bubbles in Figs. 17 and 18 represent the water saved/lost with respect to the BAU scenario. The hollow circle represents water lost and solid circle represents water saved. The size of the bubble signifies the magnitude of water lost/saved.

From the water-carbon cost curve, it can be inferred that the cost of mitigating carbon emissions for the power sector is high. This is predominantly because of a high investment cost for installing renewable power plants. Of all GHG mitigation scenarios, only the AESO mid growth and coal to gas conversion scenario save water; all other scenarios consume more water than in the BAU case. These results indicate that the implementation of climate change scenarios lead to higher water consumption in the power sector. The coal-to-gas conversion 2030 scenario results in approximately zero GHG mitigation, hence it is not included in the figures.

5. Conclusion

This paper discusses the developmental method and the results achieved for the integrated WEAP and LEAP scenarios. Authors drew on a wide range of data, built computer models and used them to visualize future climate change scenarios. An integrated water-energy model developed for power sector in Alberta provides a customized water-energy analysis based on various climate change scenario. For the same input data of the annual activity of the power sectors, the two integrated models provide the water demand results along with the variations in electricity supply and GHG emissions under the scenarios considered. This paper further assists policy makers and industrial stakeholders to make a responsible long-term decision in power sector and understand tradeoff between GHG emissions and water demand. Modelling methodology from this paper can be adopted to analyze other regions with necessary modification in input parameters.

The objective of this paper included detailed water-energy nexus model development from 2015 to 2050. This study provides a detailed analysis to understand the pattern of future water and electricity supply for power sector. It can be summarized that for BAU scenario GHG emissions and water demand decrease by around 44% and 34%, respectively, in 2030 due to the retirement of most of all the coal power

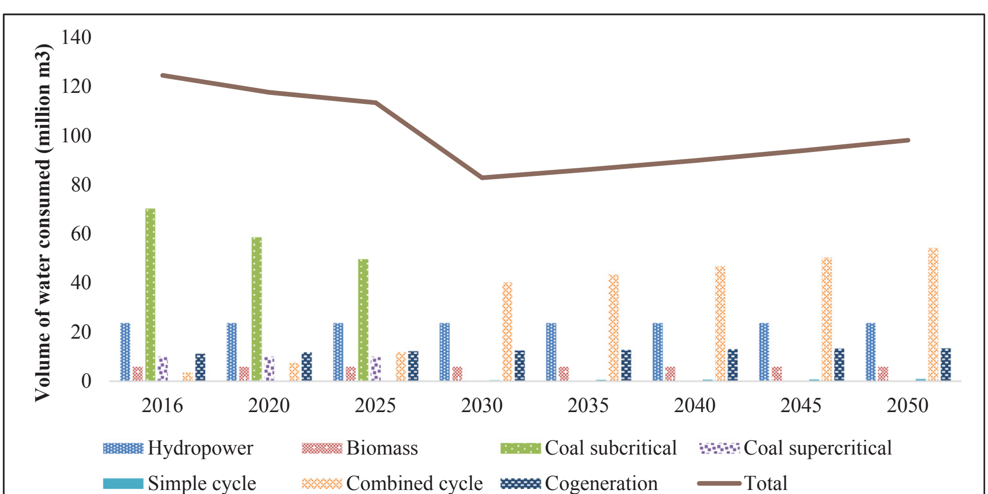


Fig. 13. Technology wise share of water consumption for the reference scenario.

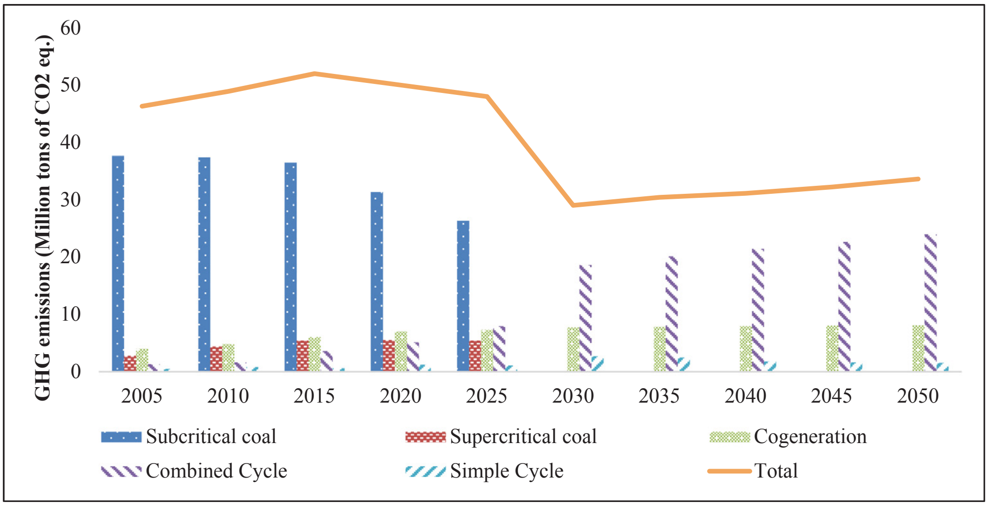


Fig. 14. Technology wise share of GHG emissions for the reference scenario.

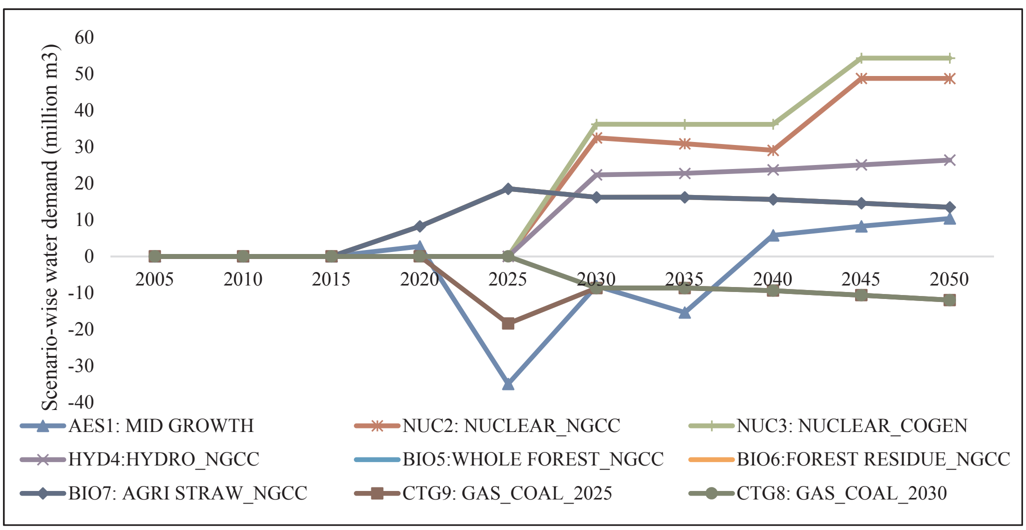


Fig. 15. Summarized water demand by scenario compared to the reference scenario.

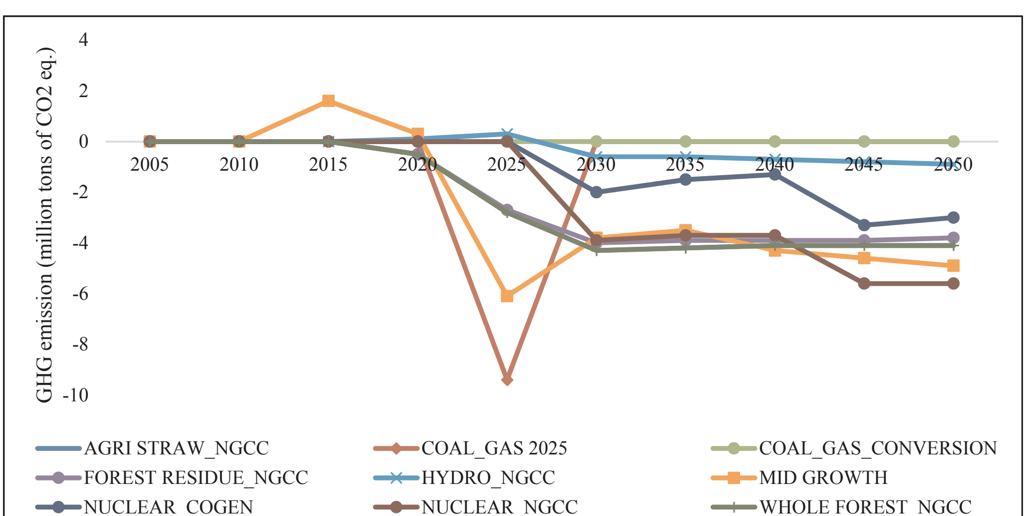


Fig. 16. Summarized GHG emissions by scenario compared to the reference scenario.

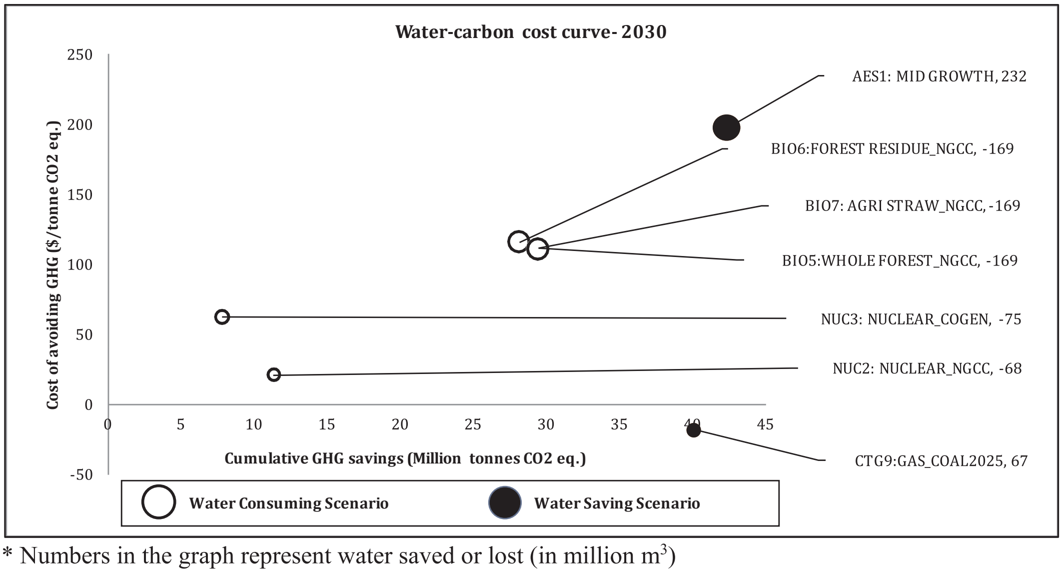


Fig. 17. Water GHG cost curve for Alberta's power sector for planning horizon 2030.

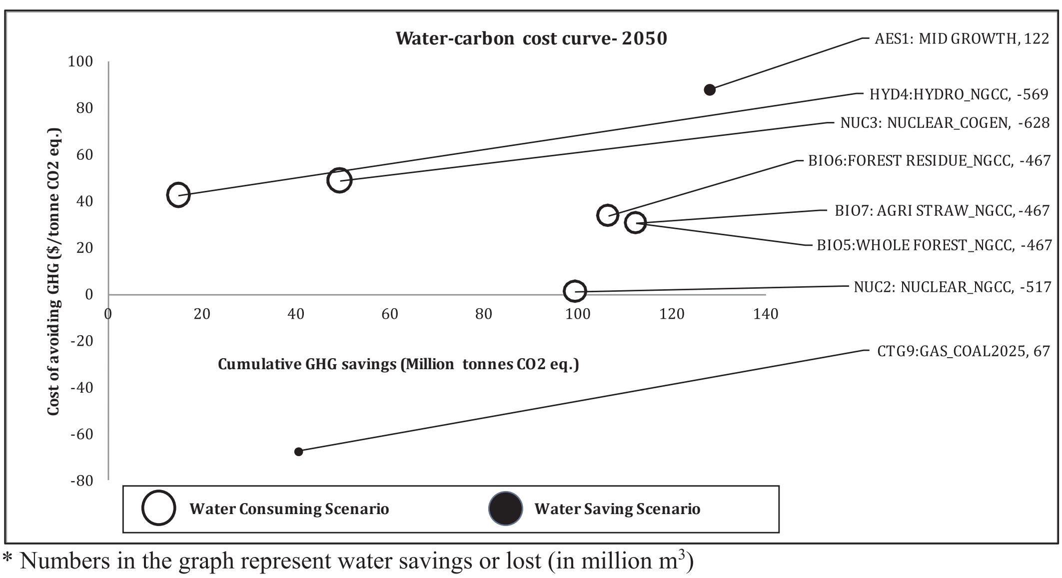


Fig. 18. Water GHG cost curve for Alberta's power sector for planning horizon 2050.

plants by 2030. The overall increase in GHG emissions and water demand from 2030 to 2050 is 16% and 19.5%, respectively. The demand site coverage for all the sectors of all the river basins under study is 100% in WEAP model.

From the results of the integrated scenarios, it can be deduced that for power sector although implementation of climate change scenarios will result in reduced GHG emissions but will increase the water demand. For the power sector, coal power plants are more GHG and water intensive than natural gas power plants. Since the coverage is 100%, it can be deduced that the water resources have enough water to fulfil the needs for different climate change scenarios, if the river flow pattern in future remains same as from 2005 to 2015. Early coal to gas conversion is the only scenario that is expected to save water (67 million m^3), reduce emissions (40 million tonnes of CO_2 eq.) while staying cost effective ($68/tonne of CO_2 eq.). Hence, countries or states that are heavily dependent on coal power plants and plan to decrease their emissions can consider converting their coal power plants to natural gas power plants.

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Appendix A. Supplementary material

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.apenergy.2018.02.116.

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